Case History

Analysis of generator rotor unbalance

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After a major overhaul, attempts to field balance Unit Number 3 at Consolidated Edison's Arthur Kill Station, were met with inconsistent and nonrepeatable results. The analysis of several key pieces of data led to the conclusion that the low pressure turbine's bore plug had lost its fit and fallen into the low pressure-to-generator coupling's "spacer gear" bore. This case history describes the problem and discusses the techniques used to establish the bore plug as the source of the unbalance.

Consolidated Edison's-Arthur Kill Station is located in Staten Island, New York and operates two turbogenerator sets. Unit 2 is a 335 MW steam-driven, cross compound, 13 bearing machine, while Unit 3 is a 491 MW steam-driven, 12 bearing unit which uses a tandem design. Figure 1 shows Unit No. 3's machine train layout.

On May 17, 1991, Unit No. 3 was returned to service after a major overhaul. The outage work included the installation of a Bently Nevada 3300 Turbine Supervisory Instrumentation monitoring system. Other overhaul work included boresonic inspection of the Low Pressure turbine rotors and new steam seal retractable or Brandon packing.

The 3300 monitoring system consisted of dual probes (proximity and velocity transducers) at each bearing in the X & Y directions. Data was collected, displayed and archived using a Bently Nevada System 64. System 64 is a computer-based monitoring system which performs on-line diagnostic and trending functions. The system can simultaneously collect static and dynamic data from up to 64 monitor racks. The data is extracted from the racks through ports on the back of the 3300 monitoring system. Data can then be displayed showing the entire plant's status on one screen. Diagnostic displays include Orbit, Spectrum, Timebase and Acceptance Regions, while Trend plots can be displayed for the past year.

Using System 64, station operators could, for the first time, monitor and collect real-time vibration data in a format that was useful and easy to understand. This allowed them to not only protect the Unit from dangerous vibration levels, but also to diagnose vibration problems in an informed and timely manner. As this case history illustrates, this enhanced vibration monitoring and diagnostic capability arrived at just the right time. ►

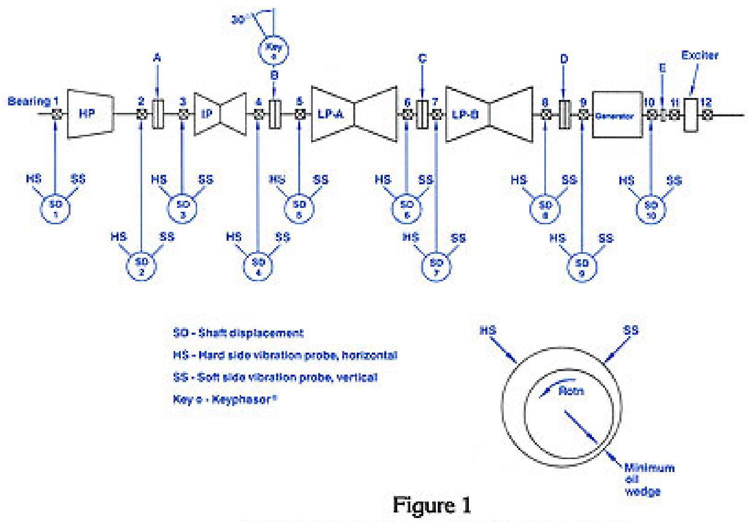

Figure 1
Turbogenerator machine train diagram

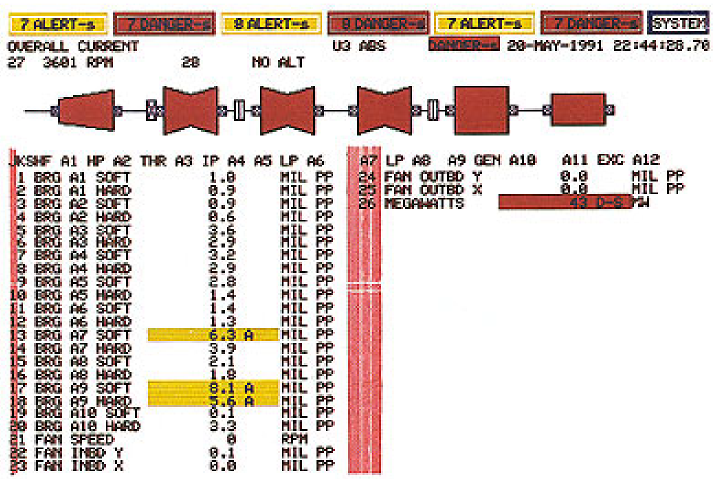

Figure 2
High vibration levels on Bearings No. 7 & 9 detected on System 64
Current Overall Values screen

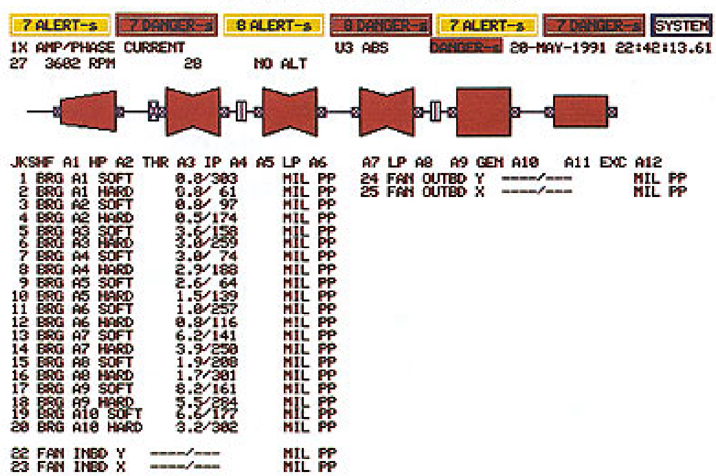

Figure 3
System 64 Amplitude versus Phase screen

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On May 20, 1991, shortly after Unit No. 3 returned to service, the vibration monitor's alarm status went into a "Danger" condition. The overall vibration levels shown in Figure 2, indicate that Bearing No. 9 was experiencing high vibration. When they viewed the synchronous or 1X frequency component (Figure 3), operators noticed that this was the major contributor to the overall vibration. They decided to install an unbalance correction weight (balance shot) in the generator rotor as an attempt to reduce its 1X vibration.

A balance shot was calculated, and correction weights were installed in the generator rotor on May 23. Figure 4 shows that, while the balance move brought Bearing No. 9's 1X vibration below the alarm levels, Bearing No. 10 was now in an Alert condition. Another balance shot, to trim the vibration down to a more acceptable level, was installed on May 26. This balance shot behaved as expected, and all parties felt that further balancing would have a beneficial effect on the unit's overall vibration levels.

After the second balance shot, the unit experienced a shutdown unrelated to vibration. Upon the subsequent startup, generator Bearing No. 10 again experienced high vibration. The vibration was most pronounced during unit transients and was predominantly synchronous (1X) in nature. This time, however, unbalance was not considered the primary cause.

Figures 5 and 6 are 1X Amplitude/Phase Trend plots for the turbine and generator, respectively. From these figures, it was concluded that the generator Bearing No. 10 (Figure 6) was responding to a turbine steam seal rub (Figure 5) and not rotor unbalance. These plots show how the 1X vector "walked out," reversed direction, and then returned to its original position. This is an example of how a steam seal rub initiates and finally rubs itself out.

Because the generator was operating close to its third balance resonance speed (Figure 7), any additional excitation, even down at Bearing No. 2, would result in an amplified response. That is why Bearing No. 10 had a greater

response to the rub than Bearing No. 2.

Arthur Kill uses System 64 to trend various process variables. It was thought that load changes may have been contributing to the rubs. This was dismissed after comparing the vibration and load Trend for Bearing No. 10 which showed that vibration was not significantly affected by changes in load.

After working out the rub, the unit operated relatively trouble-free. On June 17, an overspeed trip test was scheduled for Unit No. 3. Because the generator rotor had responded favorably to previous balancing attempts, another balance shot was attempted by placing the correction weight in the alterex-to-generator coupling at a radius of 8 inches (203 mm). For a relatively small correction weight (5 ounces or 142 grams) at the alterex coupling, the results were totally unexpected. Generator vibration increased to levels that were not consistent with either the correction weight mass or previous responses (Figure 8).

This immediately alerted the station's operating personnel to a potential problem with the generator. However, it was decided to attempt another balance shot on June 20 to verify the inconsistent results. The results once again were inconsistent with the expected response (Figure 9). The decision to continue balancing was aided by having the unit's operating conditions continuously monitored.

At this point, it was necessary to look at the balance sensitivities derived from the previous balance moves. The sensitivity derived from the first balance shot was 5.8 ounces/mil (6.4 grams/μm) at 155 degrees. This was not considered unusual for this type of rotor. After the five ounce (142 gram) change to the alterex coupling, the sensitivity had changed to 1.2 ounces/mil (1.33 grams/μm) at 105 degrees. It would seem almost impossible for a five ounce weight to have an effect of this magnitude on a sixty-two ton (56,246 kg) rotor. This inconsistency was also confirmed by the June 20 balance shot which resulted in a sensitivity of 2.0 ounce/mil (2.2 grams/μm) at 123 degrees.

The next step was to look for what could have caused this unpredictable

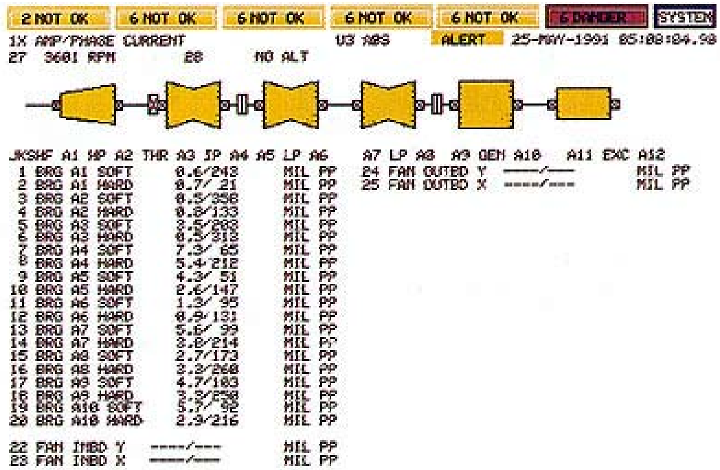

Figure 4

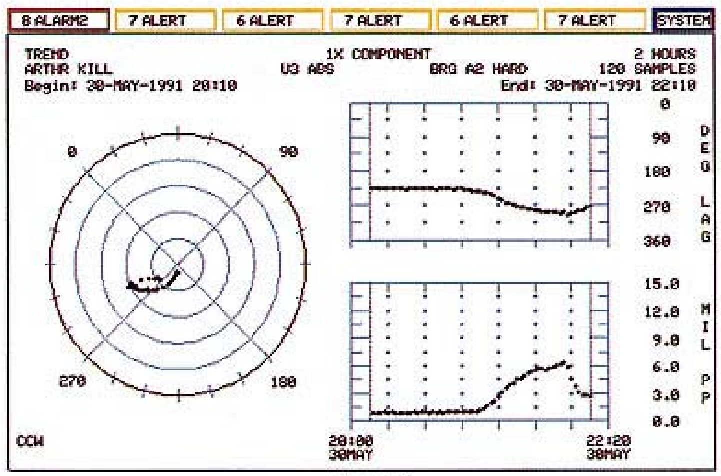

Figure 5
1X Amplitude/Phase Trend plot of the turbine

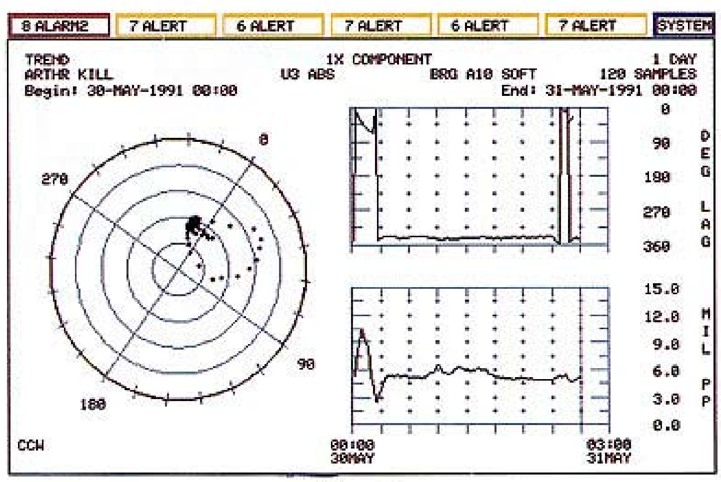

Figure 6
1X Amplitude/Phase Trend plot of the generator

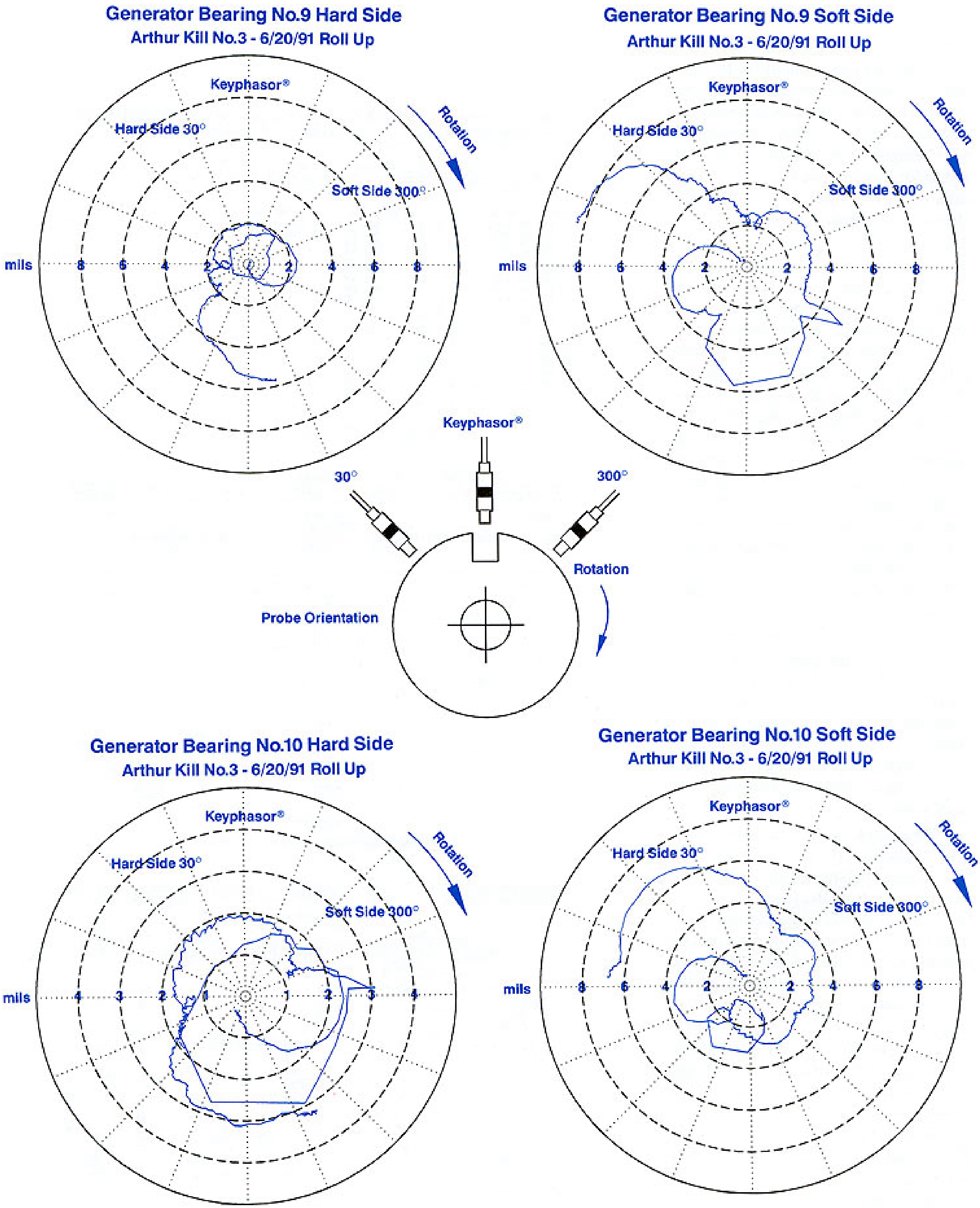

Figure 7
Polar plots of Machine Startup. Note: Third party software was used.

response to balancing. A flux test was performed on the generator which eliminated the possibility of a shorted turn. Also, transient data recorded from the monitors did not indicate that a generator resonance was responsible for the shifting 1X vibration vector. The next thing to examine were the sensitivities of each balance move. It was determined that the shifting 1X vibration vector was the result of an unbalance with an equivalent weight of 32 ounces (907 grams) at a radius of 16 inches (406 mm) at the generator rotor's balance plane. Because the "shifting 1X vibration vector" at Bearing No. 9 always led its counterpart at Bearing No. 10, the shifting mass was determined to be located at the coupling end of the generator rotor.

It was now apparent that some part internal to the generator or Low Pressure Turbine "B" was shifting position every time the unit was shut down and restarted. After a thorough investigation, it was determined that the only part internal to both rotors, with enough mass to cause the dramatic vibration shifts between balance moves was the Low Pressure Turbine's bore plug. This conclusion is supported by data collected during the June 18 overspeed test. A large step change in vibration was noted, while speed and megawatts remained constant. The step change corresponds to the point in time where the bore plug fell out. The results of a stress/strain analysis confirmed that it was possible for the bore plug to lose its fit during an overspeed condition.

Conclusions

On September 23, 1991, the Low Pressure-to-Generator coupling was disassembled and parted. As predicted, the Low Pressure rotor's bore plug was found in the coupling spacer gear's bore. Figure 10 shows how the bore plug fits into the coupling bore.

The information from System 64 was critical in arriving at a correct diagnosis of this problem. When the bore plug was reinstalled, vibration levels returned to acceptable levels. This case history documents the importance of computerized monitoring systems used in conjunction with a traditional monitoring system.

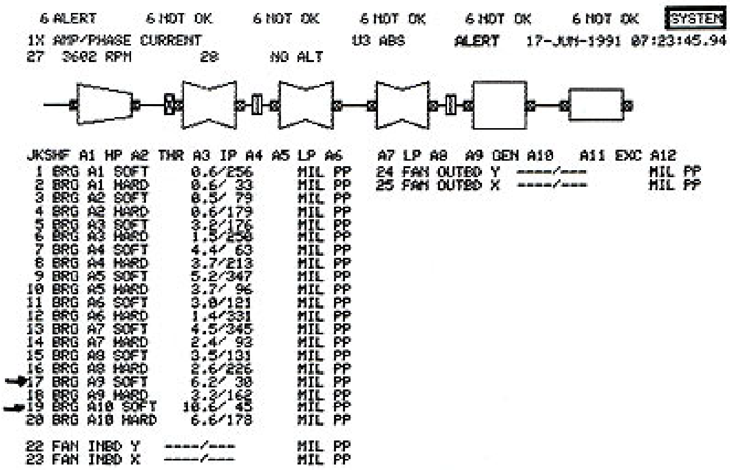

Figure 8

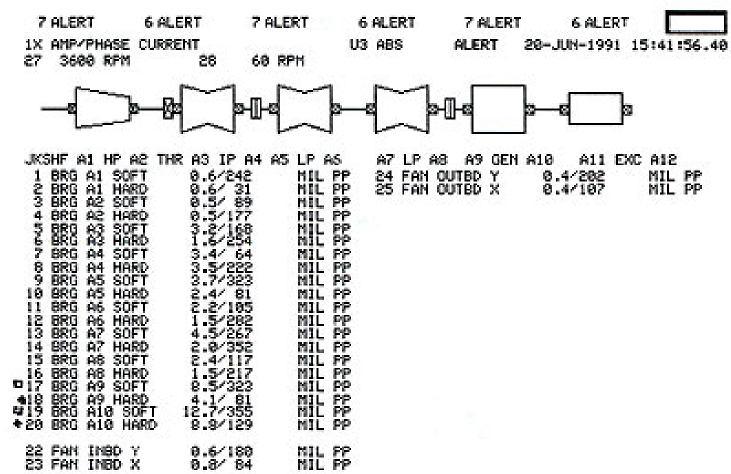

Figure 9

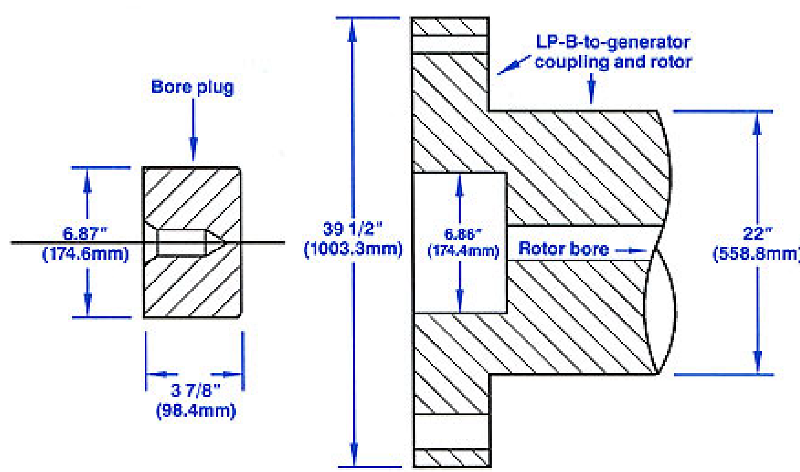

Figure 10

Diagram showing how the bore plug fits into the coupling bore